AL.1.151 c2

CANADIANA

MAR - 9 1992

ERCB

**Energy Resources
Conservation Board**

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-2

TO: All Oil and Gas Operators

1 March 1992

WELL OWNERSHIP/WORKING INTEREST OWNERSHIP – SUBMISSION REQUIREMENTS

The purpose of this informational letter is to introduce the submission requirements with respect to well ownership information.

The requirements are based upon the recommendations of the Joint Industry Task Force on Orphan Wells. This task force was formed in 1990 in response to a Board report entitled "Recommendations to Limit the Public Risk from Corporate Insolvencies Involving Inactive Wells". The task force and the Board are in agreement that working interest owners should be responsible for ensuring that abandonment procedures are conducted. In this regard, it is the task force's recommendation, with the Board's concurrence, that the ERCB collect information about working interest ownership at the following points in the life of a well:

1. Licensing
2. Transfer of Well Licence
3. Suspension
4. Abandonment

Accordingly, at each of the above points the Licensee/Operator shall

- confirm in writing that it holds 100 per cent working interest in the well, or
- if the Licensee/Operator is not a 100 per cent working interest owner, submit a list of working interest participants in the well indicating percentage participation. A summary of the contractual relationship with the mineral leaseholder should also be provided, as shown in the following example:

Working Participant	Corporate Officer	Address	Percentage Participation
ABC Oil Ltd.	J. Doe	11 - 1A Street, Calgary	50
XYZ Oil Ltd.	L. Smith	22 - 11 Avenue, Edmonton	50

MN Resources Ltd., holder of this PNG Lease 123456789, will hold a 50 per cent participation after payout.

Form DAP 1 91-12 "Application for a Well Licence" and Form D&P 5 91-10 "Inactive Well Application" have been revised to reflect these changes.

Form ED-21 91-08 "Abandonment Form" and Schedule 1 - Transfer of Well Licence (sample form) of the Oil and Gas Conservation Regulations are being revised to reflect these requirements.

Applicants requiring assistance or further information regarding this informational letter should contact the Drilling and Production Department at 297-8554 or 297-8326.

J.R. Nichol

J. R. Nichol, P.Eng.
Manager
Drilling and Production Department

AL.1.151

CANADIANA

APR - 1 1992

ERCB

Energy Resources Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-3

TO: All Pipeline Operators

11 March 1992

PIPELINE EXCAVATION PROCEDURES

Since the regulations with respect to excavation near pipelines came into force, the Board has recognized that certain of its requirements are practically difficult to comply with under certain circumstances. There have also been developments in excavation technology which the Board has recognized. The following three items outline practices which the Board accepts as meeting the intent of the Regulation.

1. Excavation procedure for exposing a pipeline more than 1.5 metres deep

The Board recognizes that the hand excavation required when a ground disturbance is intended to be carried out within 5 metres of a pipeline is not practicable when the depth of cover over the pipeline is more than 1.5 metres. Consequently the Board will accept the procedure outlined in the attachment, which allows for part of the excavation to be carried out by mechanical means. The procedure is designed to satisfy the general safety requirements for excavation of deep trenches.

2. Excavation by licensee on licensee's pipeline

Where a pipeline is to be exposed by its licensee, the licensee may make application to the Board for approval to use excavation procedures not specifically allowed for in the Pipeline Regulation and not covered by the procedure in Section 1. The application should fully describe the process, by reference to diagrams if necessary, and indicate why the licensee believes it to be a safe method of excavation.

3. Excavation using water or air jets

A number of proprietary techniques have been developed using water or air jets as the excavation tool. The Board has evaluated several of these methods of exposing pipelines and has issued letters of approval to the proprietors. Factors considered in the evaluation include avoidance of damage to pipe coating and the method of disposal of spoil.

Persons wishing to use similar or other techniques shall apply to the Board for an evaluation of the technique before using it in lieu of hand exposure of pipelines.

Questions with respect to excavation techniques should be directed to the Pipeline Department at 297-2473.

R G Evans

R. G. Evans
Board Member

Digitized by the Internet Archive
in 2015

https://archive.org/details/energyresources1992214

ATTACHMENT TO IL 92-3

EXCAVATION PROCEDURE FOR EXPOSING PIPELINE MORE THAN 1.5 METRES DEEP

1. By electronic or other depth location devices determine the location, alignment, and approximate depth of cover of the pipeline to be exposed. A minimum of three readings spaced a minimum of 3 m apart shall be taken and the alignment marked.
2. Add 25 cm to the maximum depth recorded. This sum is labelled C on Figures 1 and 2.
3. By hand dig a trench of length 2C to a depth not exceeding 1.5 m at right angles to the alignment marked in step 1.
4. If no pipeline is found excavate by mechanical means to a depth of 0.5 m less than the trench depth a square of side 2C centred on the hand-excavated trench, as shown in Figure 1.
5. Decrease the dimension C by the depth of the mechanical excavation.
6. Repeat the procedure from step 3 using a new value for C each time until the pipeline is found.
7. If the pipeline is very deep check the alignment and depth after the second mechanical excavation and adjust C if necessary.

The procedure is based on the assumption that an electronic depth location device gives a reasonably accurate alignment and depth of the pipeline to be exposed. The addition of 25 cm to the indicated depth is intended as a precautionary measure to accommodate inaccuracies in depth and alignment.

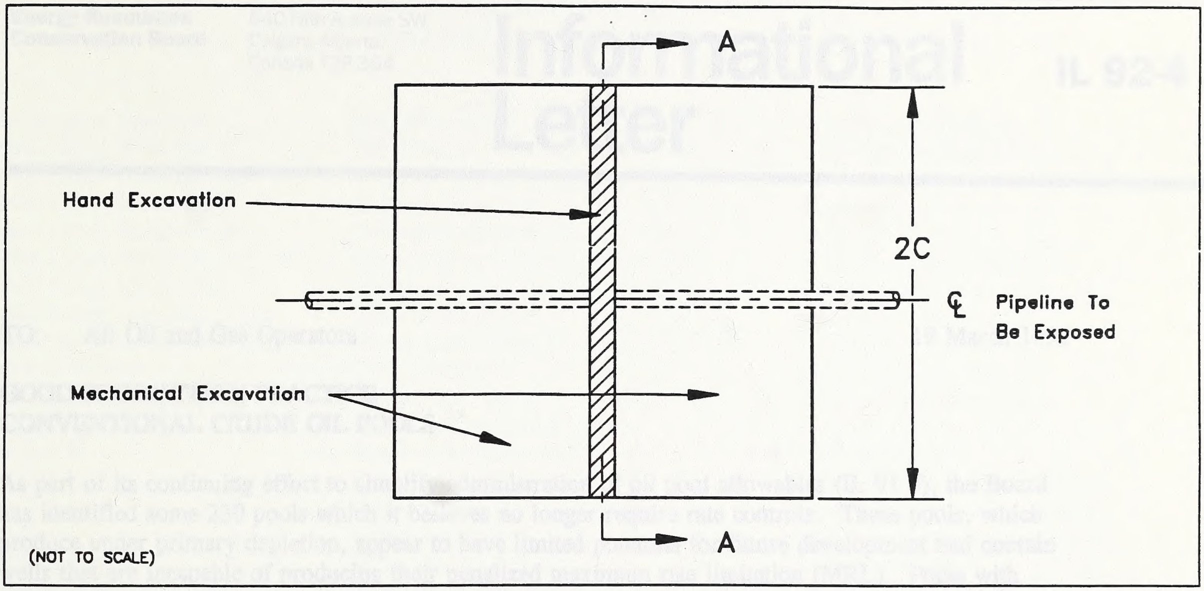


FIGURE 1 PLAN VIEW

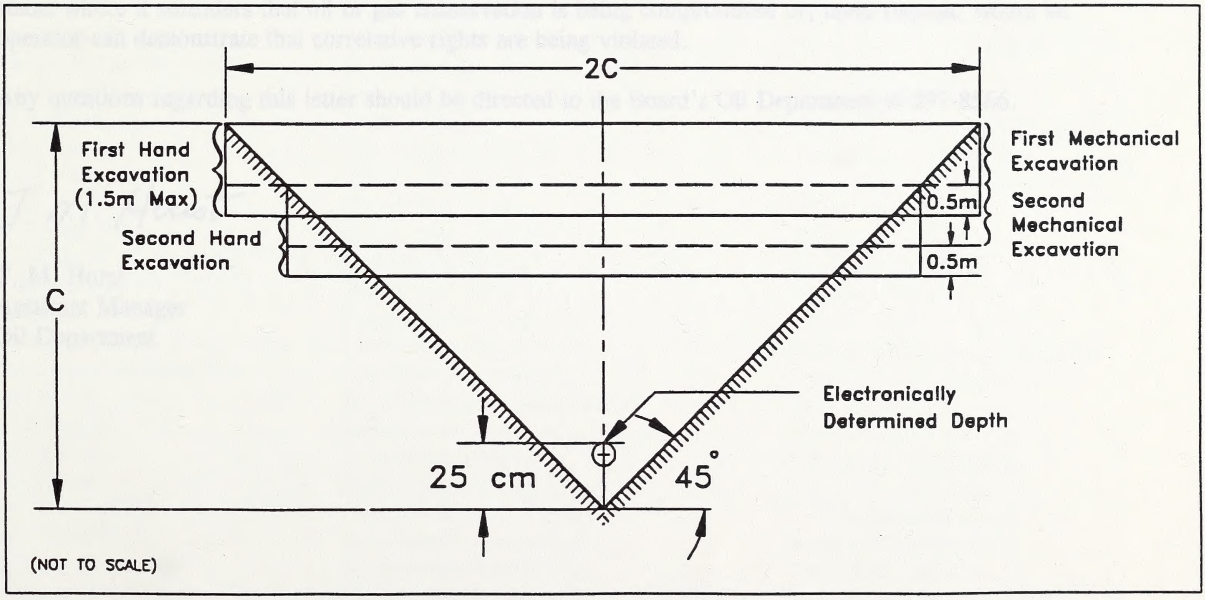

2C
First Hand Excavation (1.5m Max)
Second Hand Excavation
C
First Mechanical Excavation
0.5m
Second Mechanical Excavation
0.5m
Electronically Determined Depth
25 cm
45°
(NOT TO SCALE)

FIGURE 2 (Section AA)

.1.15 /
C.2

ERCB

Energy Resources
Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-4

TO: All Oil and Gas Operators 19 March 1992

GOOD PRODUCTION PRACTICE
CONVENTIONAL CRUDE OIL POOLS

As part of its continuing effort to simplify administration of oil pool allowables (IL 91-5), the Board has identified some 230 pools which it believes no longer require rate controls. These pools, which produce under primary depletion, appear to have limited potential for future development and contain wells that are incapable of producing their penalized maximum rate limitation (MRL). Pools with unresolved or possible gas conservation concerns were excluded from consideration for good production practice (GPP) status.

Effective 1 May 1992, the pools listed on Attachment 1 will be placed on GPP, unless written objection is received by 16 April 1992. Operators are cautioned that the Board may rescind GPP status where it considers that oil or gas conservation is being compromised or, upon request, where an operator can demonstrate that correlative rights are being violated.

Any questions regarding this letter should be directed to the Board's Oil Department at 297-8566.

T. M. Hurst

T. M. Hurst
Assistant Manager
Oil Department

ATTACHMENT 1 TO IL 92-4
POOLS TO GPP — 1 MAY 1992

Alderson Upper Mannville C
Alderson Upper Mannville U
Alderson Upper Mannville WW
Alderson Lower Mannville K
Alderson Lower Mannville O
Alderson Lower Mannville Z
Alderson Lower Mannville TT
Alderson Lower Mannville M2M
Alderson Lower Mannville O2O
Alderson Detrital A
Ante Creek Beaverhill Lake B
Barons Barons A
Belloy D-1 B
Belloy D-1 D
Belloy D-1 J
Belloy D-1 L
Bilbo A Cardium B
Bow Island Lower Mannville C
Brazeau River Belly River X
Carstairs Viking B
Cessford Mannville T2T
Cessford Basal Quartz C
Cessford Banff B
Chain Viking D
Chauvin South Colony O
Chauvin South Lloydminster E
Compeer Lower Mannville C
Conrad Sawtooth A
Craigmyle Banff I
Crossfield Viking B
Crossfield East Cardium C
Cygnet Viking A
Cygnet Viking G
Davey Belly River F
Davey Pekisko A
Dina Sparky B
Donalda Upper Mannville F
Edgerton D-2 D
Edson Cardium J
Enchant Ellis B
Enchant Ellis G
Enchant Arcs L & BB
Enchant Arcs II & JJ
Esther Upper Mannville B
Esther Upper Mannville I
Evi Slave Point A
Evi Slave Point B
Evi Slave Point H
Evi Slave Point K
Evi Slave Point N
Evi Gilwood D
Evi Gilwood I
Ferguson Lower Mannville A
Galahad Camrose A
Garrington Cardium M
Garrington Lower Mannville N & O
Garrington Lower Mannville Q, CCC & NNN
Gilwood Gilwood E
Giroux Lake Viking D
Gladys Rundle C
Golden Spike D-3 B
Grand Forks Sawtooth KK
Grand Forks Sawtooth PP
Hamelin Creek Triassic A
Hayter Colony B
Hayter Sparky L
Hayter Sparky D & E
High Prairie Gilwood A
High Prairie Gilwood B
Highvale Nordegg D & Banff H
Highvale Banff A
Horsefly Lake Mannville B
Hussar Glauconitic SSS
Hussar Ostracod X
Hussar Basal Mannville AAA
Hythe Halfway C
Innisfail Belly River A
Joffre Viking B
Kakut Charlie Lake A
Killam Ellerslie CC
Kidney Keg River I
Kidney Keg River M
Kidney Keg River W
Kidney Keg River TT
Leaman Lower Mannville G
Leckie Upper Mannville C
Leo Upper Mannville A
Little Bow Upper Mannville S
Lloydminster McLaren A
Lloydminster Sparky G
Lloydminster Sparky J
Lloydminster Sparky KK
Lloydminster Sparky ZZZ
Lloydminster Sparky B2B
Lloydminster Sparky E2E
Lloydminster General Petroleum N
Lloydminster General Petroleum X
Lloydminster Lloydminster M
Lochend Cardium A
Loon Slave Point C
Loon Granite Wash B
Loon Granite Wash J
Macleans Creek Gilwood A
Morinville D-1 B
Morinville D-3 B
Manola Lower Mannville E
Manola Lower Mannville F
Manyberries Sunburst A
Manyberries Sunburst J
Manyberries Sunburst HH
Manyberries Sunburst KK
Meekwap D-2 F
Michichi Banff D
Minnehik-Buck Lake Cardium E
Minnehik-Buck Lake Cardium Q
Minnehik-Buck Lake Ostracod G
Mooney Bluesky A
Nelson Viking A
Nevis Blairmore F
Nevis Upper Mannville A
New Norway D-2
Nipisi Slave Point A
Nipisi Gilwood H
Otter Slave Point A
Pembina Belly River M2M
Pembina Cardium P
Penhold Viking E
Penhold Lower Mannville E & H
Pine Creek Cardium P & S
Pouce Coupe South Boundary H
Prevo Viking A
Progress Charlie Lake C
Progress Halfway B
Progress Halfway R
Provost Upper Mannville C
Provost Upper Mannville MMM
Provost Upper Mannville C4C
Provost Sparky B
Provost Sparky E
Provost Lloydminster D
Provost Lloydminster H
Provost Lloydminster R
Provost Lloydminster U
Provost Lloydminster Y
Provost Lloydminster EE
Provost Lloydminster II
Provost Cummings I
Provost Cummings M
Provost Cummings N
Provost Cummings W

ATTACHMENT 1 TO IL 92-4
POOLS TO GPP — 1 MAY 1992

Provost Cummings ZZ
Provost Lower Mannville AA
Racosta Basal Quartz A
Rainbow Muskeg Y
Rainbow Keg River DD
Rainbow Keg River BBB
Rainbow South Muskeg K
Red Earth Slave Point V
Red Earth Granite Wash DD
Red Earth Granite Wash HH
Red Earth Granite Wash RR
Red Earth Granite Wash CCC
Red Earth Granite Wash EEE
Red Earth Granite Wash FFF
Red Earth Granite Wash MMM
Red Earth Granite Wash G2G
Red Willow Lower Mannville K
Redwater Ellerslie C
Retlaw Mannville R
Retlaw Mannville Q2Q
Ribstone Nisku B
Ribstone Nisku A & Camrose A
Ricinus Cardium H
Rosevear Second White Specks A
Rowley Viking C
Rumsey Lower Mannville F
Rycroft Halfway B
Saddle Hills Charlie Lake A
Seal Slave Point D
Shadow Gilwood D
Shadow Gilwood H
Sinclair Doe Creek I & J
Skiff Sawtooth B
Slave Slave Point L
Slave Slave Point S
St. Albert-Big Lake St. Albert D-3 B
Steele Grand Rapids R
Stettler D-3 B
Sunset Triassic B
Swalwell Pekisko F
Sylvan Lake Viking W
Taber South-East Mannville C
Taber South-East Mannville D
Tangent D-1 F
Three Hills Creek Pekisko B
Tindastoll Belly River A
Trout Keg River-Granite Wash A
Turin Lower Mannville H
Turin Lower Mannville NNN
Twining Lower Mannville J
Utikuma Lake Keg River Sandstone H
Valhalla Doe Creek M
Valhalla Boundary I
Verger Upper Mannville C
Wainwright Colony G, R, V, W & EE
Wainwright General Petroleum C
Watts Banff D
Watts Banff I
Watts Banff M
Watts Banff Y
Watts Banff Z
Wayne-Rosedale Basal Quartz GG
Wildmere Sparky N
Wildmere Sparky O
Wildmere Lloydminster P
Willesden Green Belly River V
Willesden Green Belly River EE
Willesden Green Belly River MM
Willesden Green Cardium E
Willesden Green Second White Specks E
Wilson Creek Belly River D
Wrentham Glauconitic B
Wrentham Lower Mannville E
Wrentham Lower Mannville F
Wrentham Lower Mannville G
Zama Keg River A2A

ERCB

**Energy Resources
Conservation Board**

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-5

To: All Oil and Gas Operators

26 March 1992

CANADIANA
APR - 3 1992

REDUCED FLUID SAMPLING AND ANALYSIS REQUIREMENTS FOR HYDROCARBON MISCIBLE FLOOD SCHEMES

Background

Board approvals for miscible flood schemes have clauses outlining sampling and analysis requirements for determining produced solvent and chase-gas volumes. The requirements for progress reports are also specified in the approvals. There is a wide variation in the sampling and analysis practices, and in the contents of the progress reports. Many operators have questioned the need for liquid-phase samples and four applications have been filed to reduce or waive sampling requirements in certain pools. To resolve these matters and to avoid an ad hoc solution, Board staff met with all miscible flood operators in December 1991 and January 1992, and subsequently received written comments from six operators. This letter summarizes the changes to, and implementation of, Board policy as a result of these applications and meetings.

Findings

During the meetings, there was some debate respecting the purpose of the sampling and analysis program. Some operators said the program was designed to provide information for evaluating scheme performance (i.e. hydrocarbon conservation). Other operators said it could only be used to forecast future recovery of the injected solvent and chase gas (i.e. resource appraisal). In view of the different opinions, the Board reaffirms its historical position that the purpose of the program is to *quantify* produced volumes of solvent and chase gas on an *individual-well basis* and is primarily intended as a performance evaluation tool.

Most operators agreed that current liquid sampling requirements are unnecessary in the majority of pools and costly relative to the additional information obtained. Operators generally stated that reliable produced volumes could be determined from less costly gas sampling. Given the widespread nature of this opinion, the Board will delete liquid sampling requirements from the miscible flood approvals. However, in those few pools wherein some liquid sampling is required to validate the compositional analysis method, operators are requested to involve Board staff in deciding the locations and frequency of wells to be surveyed.

The Board received almost unanimous feedback from operators that sampling of representative wells is not a reasonable method for determining breakthrough volumes at individual wells. The Board agrees with this “all-or-nothing” approach and will, therefore, no longer accept representative producer-well sampling as its minimum requirement.

One of the Board's major concerns is that the methods used by operators to determine breakthrough volumes have not been properly documented for a majority of the ongoing schemes. This leads to confusion, uncertainty, and increased monitoring costs.

Gas Sampling Requirements for Producing Wells

Gas samples shall be taken and analysed quarterly for *all* producing wells:

(a) during any period with simultaneous production of solvent and chase gas, where no other method is available for estimating breakthrough volumes of each fluid, and

(b) throughout the life of any scheme where the total breakthrough volume cannot be estimated by excess gas production (GOR method discussed next).

Situations where the GOR method may not be reliable include

- schemes with an initial gas cap,
- schemes with prior gas injection, or
- schemes with measurement difficulties.

Situations where the GOR method is most likely to be reliable include

- high-pressure, lean-gas schemes with continuous solvent injection and no chase-gas injection phase,
- the solvent injection phase in most schemes, or
- the late chase-gas injection phase where very little solvent (<10% of the total breakthrough fluid stream) is being produced.

Fluid Sampling Requirements for Injection Wells

The Board will continue to require that injected solvent and chase gas be sampled and analysed on a monthly basis. *Operators should note that this information should now be submitted with progress reports rather than on a monthly basis.*

Reporting Requirements

Progress reports must include

(a) either an explanation of the method being used to determine solvent and chase-gas breakthrough volumes and compositions, with a detailed example calculation, or a reference to a previous report that outlines the method,

(b) either monthly and cumulative volumes of produced solvent and chase gas on an individual-well and scheme basis, or the allocation factors used to calculate the breakthrough volumes,

(c) monthly and cumulative compositions of produced solvent and chase gas summarized on a scheme basis, and, where appropriate, this information could also be summarized on a pattern, area, stage, or phase basis, and

(d) monthly and cumulative compositions of injected solvent and chase gas summarized on a scheme basis.

Implementation

The Board is proceeding to grant requests to delete liquid sampling requirements in the Judy Creek Beaverhill Lake A and B Pools operated by Esso Resources Canada Limited (Application No. 900645), in the Pembina Nisku schemes operated by Esso Resources Canada Limited (Application No. 901033), and in the Mitsue Gilwood A Pool operated by Chevron Canada Resources (Application No. 910787). For Application No. 911273 by Chevron Canada Resources, requesting approval to discontinue oil and gas sampling requirements in its eight Nisku schemes in the Bigoray, Brazeau River, Pembina, and WestPem Fields, the Board has

- approved discontinuation of liquid sampling requirements in all eight schemes,
- approved discontinuation of gas sampling requirements in the four high-pressure lean-gas floods (Pembina Nisku A, WestPem Nisku A, C and D Pools), but has
- retained the requirement of gas sampling and analysis in the four rich "slug" schemes (Brazeau River Nisku B, Bigoray Nisku F, and Pembina Nisku D and F Pools).

Over the past year, the Board has deferred a number of miscible flood approval amendments pending completion of the current review. The Board will now proceed to revise these approvals to be consistent with the updated sampling, analysis, and reporting requirements. The Board notes that, in the case of the Judy Creek Beaverhill Lake A and B Pools (operated by Esso), the Swan Hills South Beaverhill Lake A and B Pool (operated by Amoco), and the Nipisi Gilwood A Pool (operated by Amoco), discontinuation of the "representative" well option could substantially increase sampling costs. Therefore, the Board will not impose the stricter requirements in these four schemes at this time. Instead, Board staff will be contacting Esso and Amoco in the near future to discuss the need for continued sampling.

The Board believes that the revised requirements will result in significant savings for operators without jeopardizing the purpose or value of the data gathered. Any application to further reduce or modify sampling requirements will be considered by the Board on a case-by-case basis.

The Board appreciates the operators' help in responding to this sampling issue in a comprehensive and timely manner. Any questions, comments, or concerns should be directed to Tom Keelan (297-8549) or Barry Christensen (297-4102).

R.A. Purvis

R. A. Purvis, P.Eng.
Manager
Oil Department

ERCB

Energy Resources
Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-6

To: All Oil and Gas Operators

20 April 1992

GAS WELL TESTING
PROVINCIAL PROGRAM OF SUBSURFACE PRESSURE SURVEYS FOR GAS POOLS

On 16 April 1990, the Board issued Informational Letter IL 90-4 which contained Guide G-40 "PRESSURE AND DELIVERABILITY TESTING OIL AND GAS WELLS – Minimum Requirements and Recommended Practices" as the province's new regulatory policy for the testing of oil and gas wells. The new policy allows for more flexibility in well testing and, at the same time, places more responsibility on the co-ordinating operator for test quantity and quality. In keeping with the intent of this new regulatory environment, the Board's Gas Department will no longer be issuing its general bulletin entitled "199_ PROVINCIAL PROGRAM OF SUBSURFACE PRESSURE SURVEYS FOR GAS POOLS".

However, the Board's Gas Well Test Surveillance and Monitoring System can generate an individualized Scheduling Report for the operator, if he desires, that will provide a tabulated summary relative to Guide G-40's minimum well testing guidelines for the operator's specific wells by field/pool. The Board believes the report could provide a cost-effective starting point for scheduling of annual gas well tests. However, it is the operator's responsibility to assess the specific testing needs and he may find that more than the nominal minimum testing requirements indicated in the guide may be necessary.

The Board reminds operators that testing programs that fail to meet the minimum requirements outlined in the guide must be submitted for Board concurrence. Board staff will continue to monitor the operators' well testing and data gathering practices and provide feedback where necessary.

Also available upon request would be a Provincial Gas Well Test Scheduling Report that would indicate the annual testing requirements for all fields and pools in the province. Both the operator report and the provincial report are available for a nominal fee and may be ordered upon request to the Pressure and Deliverability Group of the Board's Gas Department. Appendix 1 to this informational letter provides a sample copy of these reports.

Should you have any comments or further questions regarding this matter or the Scheduling Report, please feel free to contact either Ms. Cindy Johnson at 297-2571 or Mr. Richard Gowan at 297-8347, both of the Board's Gas Department.

Keushnig

H. R. Keushnig, P.Eng.
Manager
Gas Department

APPENDIX 1

1992 SCHEDULE OF PRESSURE TESTS FOR: 00010

TEST CO-ORDINATOR: XYZ Oil Company Ltd.
1234 Fifth Street
Calgary, Alberta A1B 2C3

FIELD	POOL	EXEMPTION STATUS	WELL IDENTIFIER	LAST TEST PRESS/AOF	REMARKS
ABEE	LOWER MANNVILLE A		XX/99-99-999-99W9/9	1991/1988	
			XX/99-99-999-99W9/9	1991/1987	
			XX/99-99-999-99W9/9	1989/0000	INITIAL AOFP REQUIRED
			XX/99-99-999-99W9/9	1987/1987	
			XX/99-99-999-99W9/9	1988/1988	
			XX/99-99-999-99W9/9	1990/1989	
2 PRESSURE TESTS DUE IN 1992					
ABEE	VIKING Z		XX/99-99-999-99W9/9	1988/0000	INITIAL AOFP REQUIRED
1 PRESSURE TEST DUE IN 1994					
EDSON	BLAIRMORE F	EXEMPT	XX/99-99-999-99W9/9	1990/0000	
EDSON	GETHING A	DEFERRED	XX/99-99-999-99W9/9	1986/1986	
			XX/99-99-999-99W9/9	1987/1987	
			XX/99-99-999-99W9/9	1986/1986	
1 PRESSURE TEST DUE IN 1992					
FERRIER	MANNVILLE A		XX/99-99-999-99W9/9	1991/1988	
			XX/99-99-999-99W9/9	1991/0000	INITIAL AOFP REQUIRED
		EXEMPT	XX/99-99-999-99W9/9	1988/1988	
		EXEMPT	XX/99-99-999-99W9/9	1987/1987	
			XX/99-99-999-99W9/9	1988/1988	
			XX/99-99-999-99W9/9	1990/1989	
1 PRESSURE TEST DUE IN 1992					

1992 PROVINCIAL SCHEDULE OF PRESSURE TESTS

FIELD	POOL	EXEMPTION STATUS	WELL IDENTIFIER	LAST TEST PRESS/AOF	REMARKS
ABEE	VIKING Z		XX/99-99-999-99W9/9	1988/0000	INITIAL AOFP REQUIRED
	1 PRESSURE TEST DUE IN 1994				
ABEE	LOWER MANNVILLE A		XX/99-99-999-99W9/9	1991/1988	
			XX/99-99-999-99W9/9	1991/1987	
			XX/99-99-999-99W9/9	1991/0000	INITIAL AOFP REQUIRED
			XX/99-99-999-99W9/9	1988/1988	
			XX/99-99-999-99W9/9	1987/1987	
			XX/99-99-999-99W9/9	1989/0000	INITIAL AOFP REQUIRED
			XX/99-99-999-99W9/9	1991/1987	
			XX/99-99-999-99W9/9	1987/1985	
			XX/99-99-999-99W9/9	1988/1988	
			XX/99-99-999-99W9/9	1990/1989	
	3 PRESSURE TESTS DUE IN 1992				
ABEE	LOWER MANNVILLE B		XX/99-99-999-99W9/9	0000/0000	INITIAL AOFP REQUIRED
	1 PRESSURE TEST DUE IN 1992				
BIGORAY	GETHING A	DEFERRED	XX/99-99-999-99W9/9	1986/1986	
			XX/99-99-999-99W9/9	1987/1987	
			XX/99-99-999-99W9/9	1986/1986	
	1 PRESSURE TEST DUE IN 1992				
BISON	MCMURRAY F	EXEMPT	XX/99-99-999-99W9/9	1990/0000	
CARBON	BANFF A		XX/99-99-999-99W9/9	1990/1990	
	1 PRESSURE TEST DUE IN 1994				
CESSFORD	VIKING S		XX/99-99-999-99W9/9	1989/0000	INITIAL AOFP REQUIRED
	1 PRESSURE TEST DUE IN 1993				

ERCB

Energy Resources
Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-7

TO: ALL OIL AND GAS OPERATORS

13 May 1992

1992 ADMINISTRATION FEE ON WELLS AND OIL SANDS PROJECTS

The Board has set the 1992 Administration Fee at 84.0 per cent of the rate specified in sections 16.070 and 16.080 of the Oil and Gas Conservation Regulations, and invoices will be mailed on 6 July 1992. This factor is reduced from last year's factor of 85.0 per cent.

Where the operation of a well is undertaken by a contract operator, the fee will be directed to the owner rather than the operator upon the written request of the owner. This request should include a complete description of the well and the name of the operator, and should be addressed to the attention of Ms. Y. Jamal and forwarded to our office no later than 12 June 1992.

N. G. Berndtsson
Board Member

AL. 1. 157

ERCB

Energy Resources
Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-8

To: All Oil, Gas, and Oil Sands Operators

25 May 1992

CRUDE OIL PIPELINE TRUCK TERMINAL MEASUREMENT GUIDELINES

A significant portion of the province's crude oil production is trucked to pipeline terminals for disposition to market. The measurement of the crude oil at the truck terminal is a custody transfer measurement which determines total oil battery production. From Industry's perspective, this measurement represents a significant revenue point. From the ERCB's and Department of Energy's perspective, this measurement provides the total battery production which is subsequently allocated back to individual producing wells for engineering, equity, and royalty purposes. As a result of concerns and queries as to the quality of this measurement, a committee comprised of Industry, ERCB and Government representatives was formed to establish practices and procedures for both crude oil volume and quality determination.

The Crude Oil Truck Terminal Measurement Review Committee has developed guidelines for measurement of this product. As the ERCB is a stakeholder in ensuring accurate truck terminal measurement the committee believed the ERCB, through this Informational Letter, to be the appropriate means of communicating these guidelines to the industry. The guidelines developed by the committee are attached to this IL.

It should be noted that these guidelines refer to the custody transfer of pipeline quality crude oil and should not be confused with those of ERCB Informational Letter IL 90-6 pertaining to the receipt of trucked emulsion at proration batteries.

The scope of the committee's work focused on light and medium crude oils with densities ranging from 760-900 kilograms per cubic metre. Heavy oil was not directly considered due to the comparatively small volumes trucked to pipeline terminals, although many of the practises and procedures may well be appropriate for heavy oil also.

The attached guidelines represent a summary of the recommendations of the committee. Significant background work has been conducted to support the guidelines which has not been included in the attachment. A copy of the complete report of the committee is available for reference by interested parties at the ERCB Library, 2nd Floor, 640 - 5th Avenue SW, Calgary.

Effective immediately, it is expected that these guidelines be considered and followed at all crude oil pipeline truck terminals. Deviations from these guidelines would be appropriate only where such alternative methods have been proven to be capable of providing equivalent or better accuracy.

Questions or concerns regarding these guidelines should be directed to Mr. Rob Cox of the Board's Drilling and Production Department at 297-8448.

J.R. Nichol

J. R. Nichol, P.Eng.
Manager
Drilling and Production Department

ATTACHMENT TO IL 92-

GUIDELINES FOR CRUDE OIL TRUCK TERMINAL MEASUREMENT

The information contained within this attachment represents guidelines and recommended practises for the quantitative measurement of light and medium crude oils (760-900 kg/m^3) at pipeline truck terminals. The guidelines were developed by determining the level of accuracies that could be expected using common present technologies and then establishing practices to ensure these accuracies are achieved.

Strict consideration of accuracy is restricted to volume measurement. Determination of basic sediment and water (BS&W) is considered to be a qualitative matter and although reference is made to matters of sampling and density/BS&W determination, no attempt has been made to calculate associated accuracies or uncertainties.

It is expected that these guidelines will be used by all parties involved in measurement of crude oil deliveries to pipeline truck terminals to establish practises and procedures to ensure the accuracy of this measurement.

1.0 ACCURACY REQUIREMENTS

Crude oil truck terminal measurement is a custody transfer measurement requiring tight limits on measurement uncertainties. Schedule 9 of the Oil and Gas Conservation Regulations specifies a permissable error of 0.5% for total battery production, which is typically a custody transfer measurement. It is recognized, however, that terminals receiving smaller volumes of crude oil may warrant some relaxation of acceptable measurement accuracy standards.

1.1 Accuracy

The following limits are recommended based on the level of production received at a truck terminal location:

Level of Production	Maximum Uncertainty
Less than 100m^3/d	1.0%
Greater than 100 m^3/d	0.5%

Note that locations handling less than 100m^3/d currently account for less than 5% of all production trucked to terminals.

1.2 Operating Guidelines

To achieve the recommended accuracy limits, volumetric measurement resolution must be 0.01 m^3. Positive displacement (PD) meters, weigh scales and stationary tanks may be used to achieve 0.5% uncertainty in accordance with these guidelines. Truck gauge measurement, however, can only achieve 1.0% uncertainty following these guidelines.

1.3 Uncertainty Analysis

The guidelines are based on statistical uncertainty which has been calculated using the "root-sum-square" method. While it is recognized that there are many methods of determining statistical uncertainty, this method was used due to its simplicity and the varying degrees of component uncertainty. This is consistent with an accepted method referenced in the API Manual of Petroleum Measurement Standards (API-MPMS), Chapter 13, *Statistical Aspects of Measuring and Sampling.*

The calculation of statistical uncertainties required consideration of certain minimum accuracy or resolution capabilities of specific devices or instruments. In all cases the instrument accuracies are achievable through the use of standard and readily available equipment. Details of instrument accuracies and resolutions used in uncertainty calculations are given in Appendix 1.

2.0 VOLUME DETERMINATION

2.1 Lease Tank Gauges

To determine the net volume of crude oil in a transaction it is necessary to gauge the tank twice (before and after an oil transfer) then determine the difference in height. This height is converted to volume through the use of gauge tables which have been calculated using measurements of the tank. The temperature and density of the tank contents must then be taken in order to correct the indicated volume to standard conditions. During the transaction if dissimilar oils are mixed a shrinkage may occur and any associated errors may have to be accounted for.

The following items contribute to the overall uncertainty:

- Tank strapping uncertainty
- Gauge tape uncertainty
- Gauge reading uncertainty
- Temperature reading uncertainty
- Shrinkage uncertainty due to mixing

Lease tank gauging can provide the required level of accuracy if conducted in accordance with the following:

- Gauging must be done according to API Standard 2545, *Method of Gaging Petroleum and Petroleum Products*

- Tank calibration must be performed according to API Standard 2550, *Measurement and Calibration of Upright Cylindrical Tanks*, or equivalent.

- The minimum volume that can be unloaded (V_m) is determined by the formula

$$V_m = \alpha d^2 \ (m^3)$$

Where d is the diameter of the tank in metres
α is the accuracy coefficient
= 0.92 for 0.5% uncertainty
= 0.39 for 1.0% uncertainty

Example:
The minimum volume that can be unloaded to a commonly used $164.9m^3$ (1000 bbl) tank of 6.09m diameter to meet an uncertainty of 0.5% would be calculated as follows:

$$V_m = \alpha d^2$$

Where $\alpha = 0.92$ for 0.5% uncertainty
$d = 6.09m$

Therefore: $Vm = 0.92\ (6.09)^2$
$= 34.12m^3$

For comparison, the minimum volume required to be unloaded to the same tank to achieve an uncertainty of 1.0% would be calculated as follows:

$$V_m = 0.39\ (6.09)^2$$
$$= 14.46m^3$$

- Errors due to shrinkage need to be accounted for according to API Bulletin 2509C, *Volumetric Shrinkage Resulting From Blending Volatile Hydrocarbons with Crude Oils* if the difference between the density of the load and the density of the product in the tank exceeds 40 kg/m^3.

2.2 Weigh Scales

Custody transfer of crude oils can be measured to within 0.5% uncertainty using a truck weigh scale. Using larger net loads in comparison to the truck weight, the accuracy can be further enhanced. That is, the smaller the net weight in comparison to gross vehicle weight, the greater the uncertainty in the measurement. Other measurement inaccuracies can be caused by loss of weight other than the payload. These inaccuracies can be significantly reduced by following guidelines for good measurement practice.

The procedure for determining the volume of liquid on a truck using a scale is to weigh the truck before and after loading or unloading and determining the difference to obtain the net weight. To determine the density of the load a representative sample must be obtained and the density and temperature measured with a hydrometer and thermometer. The observed density must then be corrected to 15°C. The net weight determined during the weighing process divided by the sample density results in the net volume trucked.

It is recommended that 0.5% be used as the guideline for uncertainty for truck terminal measurement by weigh scales. The following items contribute to the overall uncertainty:

- Scale resolution uncertainty
- Scale repeatability
- Scale calibration uncertainty
- Density uncertainty
- Hydrometer accuracy
- Observed temperature uncertainty
- Thermometer accuracy
- Sampling uncertainty
- Fuel consumption (uncertainty always positive)

The use of truck weigh scales can provide the required level of accuracy if the following procedures are conducted:

- The weigh scale must be approved by Consumer and Corporate Affairs Canada. Calibration of the weigh scale must be done according to the rules and procedures set out by Consumer and Corporate Affairs Canada.

- The only weight to be removed during loading and unloading must be the payload. For example:

    a) Scale must be clear of debris.
    b) Trucks must have all debris removed prior to the first weighing which could potentially be lost during the loading or unloading period (ice, snow, mud).
    c) The driver must be either in or out of the truck during both weighings.

- The design of the weigh scale must be such that the truck must be fully on the scale.

- Resolution of the final calculated truck volume must be to 0.01 cubic metres.

- To maintain an uncertainty of 0.5% or less the net weight of the payload must not be less than 40% of the gross vehicle weight with the added provision that in any case the net weight must not be less than 6500 kilograms.

- The sample used to determine the density must be representative of the entire volume being considered. The density must be determined using the equipment and procedures described in API-MPMS, Chapter 9, Section 1, *Hydrometer Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products.*

2.3 Truck Gauge Markers

The overall uncertainty that can be expected due to the individual uncertainties listed below is 1.0%. This should be used as the guideline for uncertainty for terminal measurement by truck gauge marker.

Truck trailers consist of one or more compartments. Each compartment has a hatch with a rigid steel channel extending downwards into the liquid. Several "gauge marker" plates are bolted onto the rigid channel at various heights and are wire sealed. The corresponding volume is stamped beside each marker.

The following items contribute to the overall uncertainty:

- Tank calibration
- Liquid level
- Trailer incline
- Temperature reading and associated Volume Correction Factor (VCF)

An uncertainty of 1.0% can be obtained based on the following:

- The stated depth of liquid must be within one half inch of a known gauge marker.
- The depth of liquid must be determined while the trailer wheels are level to within 15 cm over its length.
- The product temperature must be determined to within 1°C.
- The minimum load on the trailer must not be less than 65% of full load.
- The truck gauge markers must initially be set by calibration to a meter with a demonstrated uncertainty of 0.2%.

2.4 Meters

The overall uncertainty that can be expected due to normal maximum uncertainties of the individual factors listed below is 0.5% for the type of metering normally used for terminal measurement. This should be used as the guideline for accuracy for terminal measurement by metering based on the considerations listed below.

The following items contribute to the overall uncertainty:

- Meter repeatability
- Proving accuracy

- Water draw accuracy
- Maximum meter accuracy shift
- Volume Correction Factor (VCF) shift due to temperature uncertainty
- VCF shift due to density uncertainty
- Meter accuracy shift due to back pressure and viscosity fluctuations

An uncertainty of 0.5% can be achieved for truck terminal metering of medium and light crudes. The use of positive displacement (PD) meters will allow this accuracy with the following qualifications:

1. Temperature devices must be read to within 1°C.
2. The difference between actual density and compensation density must be less than 40 kg/m^3. The compensation density (mechanically-set density for ATC, user-entered density for electronic flow computers) should be a volume weighted average.
3. Flow rate must be between 30% and 100% of rated flow for the meter.
4. Product temperature must be between -10°C and +40°C. Where product temperatures exceed 40°C, it may be necessary to reduce the allowable density difference as given in item 2 to maintain a 0.5% uncertainty. In all cases, temperature compensation devices must be designed for the actual range of operating temperatures seen.
5. Proving of meters must be in accordance with the latest edition of API-MPMS, Chapter 4, *Proving Systems*.
6. Metered volumes must be determined in accordance with API-MPMS, Chapter 12, Section 2, *Instruction for Calculating Liquid Petroleum Quantities Measured by Turbine or Displacement Meters*.
7. Temperature determination must be in accordance with API-MPMS, Chapter 7, Section 2, *Dynamic Temperature Determination*.
8. Measurement resolution must be 0.01m^3.
9. Turbine metering is not recommended for unloading crude oil at truck terminals.
10. Proving should be performed at intervals frequent enough to verify meter integrity.

The minimum equipment requirements for truck terminal metering are as follows:

1. Air eliminator properly sized using good engineering practices having regard for the operating conditions and maximum and minimum flow rates of the meter.

2. Sample point to provide for obtaining a representative sample of the metered volume.

3. Positive displacement meter complete with temperature compensation. Temperature compensation can be achieved by mechanical Automatic Temperature Compensators, with or without gravity selection (ATG, ATC respectively) or through electronics using flow computers. Where manual temperature compensation is used, an average temperature based on an opening temperature (2-5 minutes after the start) and a closing temperature (2-5 minutes prior to the end) should be used.

4. Unless the prover is connected directly to the vehicle unloading the product, a proving assembly consisting of an inlet valve, outlet valve, and bypass valve is required. All bypass valves and any other valve or device located between the meter and the prover that can be a source of leakage must be designed to provide bubble tight shutoff and must provide a method of detecting leakage (ie. block and bleed).

5. A method of backpressure control to ensure operation above vapour pressure of product. This can be achieved through the existing piping configuration or the use of flow restriction devices such as orifices or valves.

6. Thermowell to provide for a temperature check. The thermowell must be located in close proximity to the meter.

7. Pressure indication point located downstream of the meter to check backpressure.

3.0 QUALITY DETERMINATION

3.1 Sampling

Procedures for determining the BS&W of individual truckloads must provide a sample or composite of several samples that will be truly representative of the crude oil product within the truck. Two basic sampling methods are available from API-MPMS; Chapter 8, Section 1, *Tank Sampling*; and Chapter 8, Section 2, *Automatic Sampling*. Automatic sampling procedures are generally preferred; however, manual or tank sampling systems and procedures may also be appropriate. Where automatic sampling procedures are used, a manual procedure should also be in place to use when the automatic system is out of service.

3.1.1 Automatic Sampling

When using automatic sampling procedures, extreme care should be taken in probe location and stream conditioning. The probe can be installed in a horizontal run of pipe provided the flow velocity is high enough to provide adequate turbulent mixing of the product in the pipeline. Table 1 of API-MPMS; Chapter 8, Section 2 should be used as a guideline to determine what flow velocity is required to provide a good concentrated mix from the bottom to the top of the pipe. Mounting the sampler probe in the mid-pipe location should provide an average concentration that will be representative of the entire stream at the sampling point.

Where adequate flow velocity is not available a suitable device for mixing fluid flow should be installed upstream of the sampling point. Mixing can be accomplished with lengths of reduced diameter piping, valves, elbows, tees, or other piping disturbances. A static mixer may also be used for mixing.

The preferred probe location is on a vertical line with adequate upstream mixing. Given a choice between vertical and horizontal lines with other conditions held constant, locate the automatic sampler probe in the vertical lines. The sampling point should be as near as is practicable to the truck unloading connection on the meter run.

Additional guidelines that should be followed when using an automatic sampling system are described as follows:

- Plastic bottles made of suitable material for handling and storage of crude oils should be used. Screw tops providing a good vapour-tight seal shall be used. All sample containers must be clean and dry when installed. Sample bottles should not be completely filled and should allow adequate room for expansion, taking into consideration the temperature of the liquid at the time of filling. Adequate sample mixing is difficult if the container is more than 75 percent full.

- The sample containers should be housed in a heated enclosure and locked to prevent any tampering with the composite sample.

- The sample lines should be as short as practical and sloped downward to reduce the possibility of plugging up the sample line.

- The minimum size of representative sample should be one millilitre per cubic metre. The volume in the composite sample container should be no less than two litres in size, which is the minimum quantity required to do an analysis for the sample.

- Care should be taken when removing the composite sample container so as not to have any spillage which could destroy the value of the composite sample.

- The sample container should be thoroughly mixed before pouring any product out of the container to do an analysis. A very important step in any analysis is to ensure the crude oil from the sample container is representative of the crude oil obtained from the unloading line.

3.1.2 Manual/Tank Sampling

Manual sampling procedures may involve obtaining thief samples from the truck tank prior to unloading or grab samples taken from the truck during the loading or unloading process. Tank samples may not be representative because:

- the concentration of entrained water is higher near the bottom,
- the interface between oil and free water is difficult to measure, especially with a wax build up in the tank, or
- the determination of the volume of free water is difficult because the level of free water may vary across the tank bottom due to a build up of wax in the tank.

Manual sampling procedures can be acceptable, however, where the product in the truckload is of a consistent quality either through mixing or due to the nature of the crude oil product. Alternatively, manual sampling can be acceptable by ensuring the number or frequency of samples obtained are sufficiently high to provide an accurate representation of the entire truckload.

3.2 BS&W Determination

The recommended procedure for determination of BS&W in crude oil is the centrifuge method as described in API - MPMS; Chapter 10, Section 4, *Determination of Sediment and Water in Crude Oil by the Centrifuge Method (Field Procedure).*

This method is considered the most practical for field determination of sediment and water. However, for the purpose of these guidelines, the following exceptions to the API procedure are appropriate:

- Toluene and Xylene (refer to API-MPMS; Chapter 10, Section 4.5.2.1)
  If consent is obtained from all parties involved, water saturated solvent at 20°C (room temperature) may be used to test crude oils heated to 60 to 70°C.
- Centrifuge (refer to API-MPMS; Chapter 10, Section 4.7.1)
  The centrifuge does not have to be heated as long as the sample maintains the minimum temperature of 52°C (125°F) for the five minute test.

- Centrifuge Tubes (refer to API-MPMS; Chapter 10, Section 4.7.2.1)
  If consent is obtained from all parties involved, existing pear jars may be used, but any new installations shall use the cone-shaped tubes that are 167 mm (6") or 203 mm (8") in length.

- Test Conditions (refer to API-MPMS; Section 10, Section 4.10.5)
  If consent is obtained from all parties involved, the specified report of deviations from the procedure is not required.

3.3 Density Determination

Density of the load may be determined by either of the following methods:

1. Samples may be collected from the receiving point and sent to an independent laboratory for analysis to determine density. The density found on this analysis would be applied to all crude oil coming from this specific well or lease. Lab tests to determine density would be conducted on a yearly basis minimum or more frequently as reservoir conditions warrant. Sample containers must be sealed to prevent a loss of light ends from the sample between the time of sampling and analysis.

2. Truck load samples or samples from automatic samplers may be tested for density as outlined in API-MPMS; Chapter 9, Section 1, *Hydrometer Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products*. If consent is obtained by all parties involved, the use of a thermohydrometer is acceptable.

APPENDIX 1 - Instrument Resolutions and Uncertainties Used in Calculating Overall Uncertainties

The following lists details of specific instrument and device accuracies and resolutions used in the calculation of overall uncertainties for truck terminal measurement.

- Gauge Tapes
  - accurate to within +/- 1 mm (1/32 inch)
  - read to within +/- 3 mm (1/8 inch)

  Note that the metric values listed here represent approximate conversions from the Imperial units published in API Standard 2545. Using a metric gauge tape, it is expected that the tape be read to the nearest millimetre.

- Thermometers
  - accurate to within +/- 0.1°C
  - read to within +/- 1°C
- Hydrometers
  - accurate to within +/- 0.3 kg/m^3
  - read to within +/- 1 kg/m^3
- Weigh Scales
  - resolution of +/- 10 kg
  - repeatability of 0.1% of load
- PD Meters
  - repeatability of 0.1%

AL. 1. 157

JUN – 8

ERCB

Energy Resources
Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-9

To: All Oil and Gas Operators

1 June 1992

REVISED REPORTING PROCEDURES - LOAD FLUIDS

In May 1989, revised production, injection and disposition reports (S-1, S-2 and S-18) were introduced. Included with the revisions was a requirement for the reporting of Load Oil transactions on the S-1 and elimination of a complicated system of codes previously used to identify load oil transactions on the S-2 report. Industry and the ERCB have found these revised load oil reporting requirements to be somewhat confusing and difficult to administer. To alleviate these concerns, the ERCB has revised the reporting procedures for reporting load oil.

To further clarify this issue, the following definitions have been developed with respect to Load Fluid and Load Oil.

Load Fluid - Load fluid is any hydrocarbon and/or water-based fluid which may be used at any stage in the life of a well (completion, servicing, regular operation or abandonment). Load fluid also includes fluids injected into a flowline between a well and the battery it produces to (eg. Hot oil, dewaxing chemicals, etc.).

Load Oil - Hydrocarbon-type fluids used as load fluid, including crude oil, condensate, refined oils, and oil-based or oil-soluble chemicals.

Although the S-1 form includes a section for the recording of load oil volumes, reporting of load oil on this form will be optional. Operators are however, required to maintain records of all load oil transactions occurring at a well for a one year period, and to make these records available to the ERCB upon request. The unrecovered portion of load oil transactions is required to be reported on the S-2 forms on a facility basis.

Upon completion of any operation requiring load fluid injection at a well producing to a proration battery, the well must be tested as soon as practicable to determine recovery rates of all fluids and retested after recovery of load fluid to establish new rates for calculating estimated production.

Hours of production reported on the S-1 report should reflect the total hours during which formation gas or liquids were produced. This includes hours when a well is recovering load fluid, while also producing formation fluids (eg. recovering load oil, and producing formation gas and/or water).

Load fluids are subject to the same measurement requirements applicable to produced or injected fluids as stipulated in Part 14 of the Oil and Gas Conservation Regulations, and applicable Interim Directives and Informational Letters.

These changes are to be made effective with July 1992 production month reporting.

The appropriate sections of the Production Accounting Handbook have been revised to clarify the reporting requirements for load fluids. Simplified examples have been included which provide direction for reporting most uses of load fluids.Copies of the revision to the Production Accounting Handbook are available from Information Services on the main floor of the ERCB building.

If you have any questions regarding this Informational Letter, please contact the Board's Drilling and Production Department at 297-2429.

N. G. Berndtsson
Board Member

[illegible]
JUN 1 3 1992

ERCB

Energy Resources
Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-10

To: All Oil, Gas, and Oil Sands Operators

5 June 1992

ORPHAN WELL FUND - 1992 ORPHAN WELL LEVY

Over the past number of years the Board has become increasingly concerned with the potential for the increase in the number of orphan wells and the associated costs of abandoning these wells.

To address this concern, the Board established the Orphan Well Steering Committee, composed of representatives of the Canadian Petroleum Association, Independent Petroleum Association, Small Explorers and Producers Association, Alberta Energy, Alberta Environment, and the ERCB to work out a solution to this problem. This steering committee looked at a number of different options, including legislative changes and funding mechanisms, and has reached an agreement respecting the establishment of an Orphan Well Abandonment Fund to cover actual expenditures for the subsurface abandonment of orphan wells.

Some further refinements of this system are expected, however, the industry associations have agreed that the 1991 orphan well abandonment expenses will be recovered through a levy against inactive wells. For the purpose of this levy an inactive well was defined as any well which recorded twelve consecutive months of nil production or injection in the 1991 calendar year, excluding abandoned wells, observation wells and domestic wells. Wells placed on production strictly for testing purposes are considered to be inactive wells. It is expected that the 1992 inactive well levy will be in the order of $40 per well with assessment through the Board's Administrative Levy System as a separate invoice on a licensee's inactive wells. The fee is payable by the well licensee and invoices will be mailed on 6 July 1992.

Any inquiries respecting this fee should be directed to 297-8442.

J.P. Prince

J.P. Prince, Ph.D.
Vice Chairman

AL. 1.151

ERCB

Energy Resources Conservation Board
640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-11

TO: All Oil, Gas, and Oil Sands Operator

26 October 1992

EXPERIMENTAL SCHEMES – RELEASE OF INFORMATION

Background

Subsection 15(2) of the Oil Sands Conservation Regulations provided for the release of information or data 10 years after an applicant completes an experimental oil sands operation. Similarly, subsection 12.150(8) of the Oil and Gas Conservation Regulations provided for the release of information or data 5 years after completing an experiment in conventional oil and gas operations. The Board undertook an internal review of these regulations some time ago after recognizing that the pace of technological change has accelerated, and that the uncertainty of site-specific properties is the primary reason for classifying some operations as experimental.

The Board concluded that, in some cases, shorter confidentiality periods would avoid duplication of experimental operations and would promote the development of Alberta's hydrocarbon resources. To this end, the Board has specified shorter confidentiality periods in its approvals for some experimental schemes. For example, cyclic steam stimulation was initially given the full confidential period, but as the technology became established, the Board reduced the term of the confidentiality period. Likewise, shorter periods have been specified for other near-well phenomena in oil sands operations such as electromagnetic stimulations and horizontal wellbores. For conventional oil and gas operations involving horizontal completions, experimental status is granted for 2 years, after which all data and information is released.

To have the regulations agree with its current practice, and to simplify its administration of these provisions, the Board asked the industry associations for their views on the changes to the regulations. Having received and considered those views, the Board has revised its administrative procedures as outlined below and the regulations have been amended as shown on the attachment.

Administrative Details

While retaining the existing provisions for 10-year and 5-year confidentiality periods, and an extension clause, the regulations have been amended to provide flexibility. The duration of confidentiality is to be addressed by the operator, at the time of application. It is to be decided upon by the Board after considering:

- the potential loss of competitive advantage if the confidentiality term were shorter,
- the potential benefits of early information release to resource conservation and development, and
- the number of similar experimental schemes in progress.

Existing experimental oil or gas schemes, whose prior approvals have no specified confidentiality periods, are "grandfathered" to conform with the regulation at the time of approval. No changes will be made to confidential periods that have been set for existing experimental oil sands schemes.

Some information obtained during the experimental operations (e.g. well logs, core analyses, and fluid analyses) will not be confidential under the terms of the experimental scheme confidentiality provisions, unless otherwise specifically addressed. For most schemes this information will remain confidential in accordance with existing regulations. When specifically addressed in an approval, this information would usually be confidential for the term of the experimental approval or the duration of experimental operations.

Experimental schemes involving novel design considerations or operating techniques may lead to the development of information of special proprietary value. Although useful to the Board staff in its examinations of the technical merit of the experimental test program, this kind of information would not ordinarily be considered of general public interest and need not be made part of an application. It should, however, be submitted as confidential information, to be made part of the progress report documentation. It would then be given the same confidential status as progress reports. For this purpose, proprietary information is limited to specific design details. All other information, describing the scheme and detailing its experimental nature, is deemed to be a routine component of an experimental scheme application and is not considered proprietary.

The amended regulations become effective immediately.

N. G. Berndtsson, P.Eng.
Board Member

Attachment

OIL SANDS CONSERVATION REGULATION

15. (2) "Notwithstanding subsection (1), where operations reports, special studies, laboratory, experimental or cost information relating to an oil sands commercial or experimental scheme concerning the development or application of a new or existing technology or improved operations are submitted to and accepted by the Board as confidential, the Board shall,

(a) after 10 years or such lesser period of time as the Board directs from the completion of the experimental operation or specified phase thereof, make the laboratory or experimental information available to the public,

(b) after 10 years or such lesser period of time as the Board directs from the submission of a laboratory report or a report of a special study or cost information from an oil sands commercial scheme to the Board, make the report available to the public, and

(c) notwithstanding clauses (a) and (b), where the operator satisfies the Board that continued confidentiality is warranted, make the information available following a further period that the Board considers appropriate.

OIL AND GAS CONSERVATION REGULATIONS

12.150 (8) Where information or data pertaining to an experiment in any field, pool or well, or pertaining to a scheme for enhanced recovery in any field or pool, or laboratory data or other information concerning the development or application of methods for the recovery of oil or gas, are submitted to and accepted by the Board as confidential, the Board shall make the information or data available to the public

(a) 5 years after approval of the scheme or after such lesser period of time as the Board directs after having consulted with the operator, or

(b) if the operator satisfies the Board that continued confidentiality is warranted after the period referred to in clause (a), following such further period as the Board considers appropriate.

(9) Notwithstanding subsection (8), the Board may make the information and data referred to in that subsection available to the public before the time referred to in that subsection if it considers that failure to release the information or data would severely prejudice the Board's position in making decisions in further proceedings or seriously restrict benefits to conservation in Alberta.

(9.1) Before making a decision on the period of confidentiality or the release of the information or data referred to in subsection (8) or (9), the Board shall afford the person who submitted the information or data an opportunity to substantiate the period of confidentiality or to justify continued confidentiality.

AL. 1. 151

NOV 1992

ERCB

Energy Resources Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-12

TO: All Oil, Gas and Pipeline Operators

1 September 1992

GUIDELINES FOR MINIMIZING DISTURBANCE ON NATIVE PRAIRIE AREAS

In February 1989, the ERCB conducted a public hearing on an application to site a well and access road on an area of native prairie grassland. One recommendation resulting from the hearing was an initiative to have the jurisdictions with land management and reclamation responsibilities jointly prepare a set of consistent guidelines which would help the industry minimize the extent to which native prairie is altered during oil and gas development. This, in turn, would usually reduce overall reclamation costs while still allowing development to take place.

The guidelines, as drafted, are not intended to delay or interfere in the current approval processes, but to provide a set of recommended practices. The surface lease acquisition process will remain the same, however, operators will be expected to implement these guidelines where applicable. For privately owned land, operators are encouraged to implement the practices while also accommodating the requirements of the land owner.

The Energy Resources Conservation Board, Alberta Environment, Alberta Energy, Alberta Forestry, Lands and Wildlife and the Special Areas Board have compiled these guidelines and will work with the industry to monitor their effectiveness in reducing the loss of native prairie grassland to oil and gas projects. It is anticipated that these practices will be reviewed within a two-year period as experience with their implementation is collected.

B. F. Bietz, Ph.D.
ERCB

Wm. Simon
Alberta Environment

M. G. Turnbull
Alberta Forestry Lands and Wildlife

for M. J. Day
Alberta Energy

J. Slemp
Special Areas Board

PETROLEUM ACTIVITY ON NATIVE PRAIRIE

GUIDELINES FOR SURFACE DISTURBANCES

SPECIAL AREAS BOARD
ENERGY RESOURCES CONSERVATION BOARD
ALBERTA ENVIRONMENT
ALBERTA FORESTRY, LANDS AND WILDLIFE
ALBERTA ENERGY

SEPTEMBER 1992

CONTENTS

1 PREFACE

2 BACKGROUND

3 SCOPE OF THIS DOCUMENT

4 THE ISSUE

5 RESOURCE MANAGEMENT PRINCIPLES

6 GUIDELINES

7 CONTACTS

8 GLOSSARY

1 PREFACE

This report was prepared by government agencies having jurisdiction over petroleum and natural gas exploration, development and production activities in the prairie and parkland areas of Alberta. It has been reviewed extensively by various interested parties and industry representatives.

The participating agencies exercise complex responsibilities for regulation and approvals, land management and reclamation on both public and private lands. This report reflects a collective consensus and is intended to provide the basis for guidelines to industry regarding how petroleum and natural gas activities should be conducted in areas of native prairie in Alberta. The intent is to provide clear, consistent and integrated standards regarding how industry will be expected to discharge its responsibilities in these areas. The guidelines in the report are just that. They are intended to provide overall guidance only. They do not change the existing process in any way, ie. licences will be issued in the regular manner, operating conditions set and reclamation inspections conducted. Site-specific circumstances have to be considered to determine the most appropriate course of action which will maintain environmental standards.

This document is a compilation of appropriate operating practices and is not intended to lay blame or single out any particular industry. Although petroleum activity is not the primary cause of native prairie loss, it is a contributor and, as such, can make a significant contribution to minimizing that loss. Initiatives have begun to address the various surface activities which occur on native prairie, and ultimately a holistic approach can be put in place.

2 BACKGROUND

Increasingly, societal concern about environmental issues is being expressed wherever resource use and land management activities take place. Native grass prairie environments have been radically transformed by human activity and are one of the most endangered natural environments in Canada. The profile of prairie conservation issues was raised significantly by the publication and release of the Prairie Conservation Action Plan (PCAP) by the World Wildlife Fund Canada and the Government of Alberta in December 1988.

The purpose of the PCAP is to influence both policy and attitudes in order to better conserve the biological diversity found in the Canadian Prairies. The plan identifies ten goals toward which government, industry and individuals should cooperatively strive. In this plan, native prairie is defined as "an area of unbroken grassland or parkland dominated by non-introduced species".

Some of the most extensive natural grasslands remaining in Alberta are found within the area administered by the Special Areas Board. Early in 1989, the Energy Resources Conservation Board (ERCB) conducted a public hearing in response to concerns expressed by a grazing leaseholder in such an area with regard to a petroleum wellsite application. In its July 1989 Decision Report D 89-3, the ERCB allowed the proposed well to proceed, but with requirements for the company to evaluate the grassland area to be disturbed, and to prepare an activity and reclamation plan designed to minimize disturbance to the native prairie. The ERCB also recommended that the various responsible agencies collaborate to develop policy guidelines aimed at affording appropriate protection for native grass prairie environments, consistent with the recommendations of the PCAP, while, at the same time, allowing reasonable access to oil and gas resources.

This guideline document is the result of discussions between representatives of the Special Areas Board (SAB), Alberta Energy, Alberta Forestry, Lands and Wildlife (AFL&W), and the Land Conservation and Reclamation Council (LCRC) under the coordination of the ERCB, and has subsequently been approved and adopted by each of these agencies.

3 SCOPE OF THIS DOCUMENT

For administrative purposes, the guidelines in this report will apply to petroleum and natural gas exploration, development, production and pipeline activity on native prairie within the core area delineated on the attached map. This boundary approximates the extent of the mixed grassland and fescue ecoregions, using administrative and geographically convenient boundaries. It is intended that the guidelines shall apply wherever native prairie is found in Alberta (including portions of the Peace River region). Outside this core area, the applicability of the guidelines will be determined on a site-specific basis.

The responsibility for identifying the presence of native prairie and the subsequent application of these guidelines will be held jointly between the appropriate agencies and the applicant. Operators are strongly encouraged to contact landowners, lessees and representatives of the Crown land management agencies (see Section 7, page 6) to determine if native prairie is present. The appropriate agencies will set operating conditions in the normal manner and these conditions will be tailored according to the significance or sensitivity of individual sites.

While these guidelines recognize that industry has the ultimate responsibility to design and carry out their operations in such a way as to adequately protect native prairie grassland, the government is also committed to aiding in this process. The Crown Mineral Disposition Review Committee (CMDRC) was formed to identify to industry wide environmental policy issues which might be associated with proposed mineral sales. While the data base for native prairie grassland is incomplete, the CMDRC member departments support the identification of significant tracts of native prairie for a proponent as early as possible in the development process. The CMDRC member departments will encourage the identification and mapping of native prairie and will provide this information industry as quickly as possible. It must be recognized that progress in mapping will occur more rapidly on public than on private land.

Over time, it will be possible to provide better direction on the applicability of the guidelines in this document. Projects are currently underway both to delineate on a large scale the boundaries of natural regions in Alberta and to map the remaining native prairie. The contacts listed in Section 7 of this document are available to discuss the site-specific activities which occur on native prairie.

4 THE ISSUE

The primary issue is the need for action to ensure native prairie areas are not permanently destroyed or subjected to unnecessary impacts as a result of petroleum and natural gas activity. This will entail an increased awareness by industry, government and the public that native prairie grassland is a rapidly disappearing ecosystem, and that the cumulative longterm impact of all development, including oil and natural gas, can be very significant. The imprint on the land is usually permanent and minimizing disturbances is the preferred strategy.

Secondary components of the issue are:

- The tolerance native grasses have to drought conditions is a property which maintains the land's vitality and any disturbance should be minimized because of the difficulty in re-establishing these native species. The benefits of minimal disturbance should be reflected in reduced construction and reclamation costs as well as reduced erosion.

- Existing guidelines for reclamation and soil management have limited applicability for prairie environments. Standard soil-stripping practices do not work in many of the difficult soil conditions in native prairie grasslands because of the difficulty in re-establishing native vegetation. Also, non-native plant species can spread into the native plant community and could result in inferior grazing and altered habitat, while also preventing the re-establishment of native species on the disturbed site.

- There is a need to properly plan for total development of an oilfield. In certain areas, there has, in the past, been a proliferation of well sites, batteries, access roads and pipelines where extensive infill development has occurred which has resulted in unnecessary disturbance of native prairie.

5 RESOURCE MANAGEMENT PRINCIPLES

All of the guidelines and conditions detailed in this document have been developed in the context of the following principles:

- Practices recommended to industry should be fair and practical.

- Reasonable opportunities for the continued exploration, development and production of petroleum and natural gas resources should be provided.

- All industrial impacts on the natural environment should be minimized. Those impacts that are unavoidable should be mitigated and must be reclaimed to an acceptable standard.

- In native prairie areas identified as being particularly sensitive or with high nature conservation values, industrial activities that impair or diminish these values are not acceptable.

- Industrial activities should be conducted in a manner consistent with the primary intent of the PCAP, ie. ensuring the continued survival of healthy native prairie ecosystems in Western Canada.

- Industry consider long-term reclamation requirements when making decisions regarding disturbance, then site and conduct the activity in a manner which reduces reclamation costs. Planning must be improved to accommodate all conservation, reclamation and supervision activities.

6 GUIDELINES FOR PETROLEUM AND RELATED ACTIVITIES

It will be the responsibility of the surface lease holder or well licensee to supervise and control disturbances. All associated contractors, inspectors and service personnel are also expected to implement the guidelines with the objective of minimizing the loss of native grassland.

6.1 General

- When brush or treed areas are encountered, extensive straight-cut lines should be avoided.

- Soil stripping should be minimized and may not always be required.

- Within lease boundaries, lease size and shape may be modified to reduce surface disturbance.

- Efforts must be made to prevent erosion wherever appropriate.

- No access will be allowed which results in ruts or breaking of the native prairie. Special operating conditions for access may be required (dry and/or frozen ground) which eliminate ruts, breaking or pulverization of native prairie.

- All debris, construction waste and discarded materials shall be removed from the area and the sites left in a clean condition.

- In critical areas, as overall environmental sensitivity increases, a comprehensive plan should be formed which identifies protection measures to be used in minimizing surface disturbances. Such a plan would address; firstly, what is present; secondly, the potential results of industrial activity; and thirdly, measures to be taken to avoid or mitigate negative impacts whenever possible. This plan should address one or more of the following items:

    1. assessment of vegetation and wildlife habitat,
    2. conservation and reclamation procedures,
    3. measures to minimize surface disturbances,
    4. waste management, and
    5. landowner/lessee notification and concerns.

- Industrial developers may be requested to hold public information sessions on proposed activities or programs.

6.2 Seismic

- Access causing surface disturbance will not be allowed in coulees or through river benchland areas. Lightweight portable drilling equipment and/or handcut lines may be acceptable on steep coulee areas.

- Existing trails will be used whenever possible and development of new trails will be minimized.

- Cuttings and debris from shot holes will be replaced and excess material will be levelled or removed.

6.3 Drilling

- Wellsite and access road location will be chosen to minimize the amount of cut and fill required. The size and shape of the site should also be modified to reduce the disturbance to surface terrain. Appropriate soil conservation is required on disturbed areas.

- Directional or slant-hole drilling should be considered to reduce the extent of environmental disturbance.

- Permanent all-weather roads will not be bladed or built for the drilling phase. Existing trails or temporary access across the prairie will be used where possible. In areas of soft or sensitive terrain, other measures (eg. geotextiles) should be considered.

- Coulees, wetlands, river benches, dry lake beds and riparian areas should be avoided when selecting wellsites.

- The method of drilling waste disposal should be considered prior to starting the drilling program. Consideration should be given to the use of fluid formulations which lessen the impact on vegetation and soil and increase the success of reclamation techniques. Native turf should not be disturbed to accommodate drilling waste disposal and alternatives to routine landspreading will be considered subject to regulatory approval.

- Remote sumps or on-site tankage may be required in single or multiple well programs. Operators will take measures to reduce the surface area required to dispose of sump material and also reduce waste volumes. Remote sumps and sump disposal should be located off native range.

- Drilling waste sumps must contain all fluids with no leakage.

- A plan indicating the location of proposed wells, access roads, pipelines, production facilities, and proposed reclamation programs may be required for the evaluation of reduced spacing programs. This plan will be reviewed for evidence of reduction of environmental impact and efficiency of land use.

6.4 Production

- Where possible, permanent production facilities should be located near all-weather main roads to avoid unnecessary road construction.

- No soil sterilants will be used in vegetation control. Selective herbicides may be applied by licensed personnel where weeds present a nuisance.

6.5 Pipeline

- Stripping the topsoil/root zone should be kept to a minimum. However, additional stripping may be required on large diameter pipelines to deal with displacement and soil bulking on some soil conditions requiring special soil construction techniques. An even distribution of pre-stripped topsoil may be accomplished by feathering excessive spoil material on a stripped area slightly wider than the trench.
- Topsoil and root zone losses at grade crossings will be prevented .
- Soil pulverization and erosion of soil on workside of right-of-way will be controlled (minimum traffic, etc.).
- Some soil conditions may require three-lift stripping procedures.
- Equipment and procedures that cause the least disturbance to the surface will be considered (ploughing-in, ditching, etc.).
- Flow lines will follow the disturbed areas of access roads wherever possible.

6.6 Reclamation

- Seed mixes which allow re-establishment of native species should be used in reclaiming disturbed areas. In certain areas, commercially available native seed species adapted to local growing conditions may be required to approximate the predisturbance diversity of the prairie vegetation.
- The siting of wellsites within areas of vegetation with high natural reclamation capability should be considered.
- Seeded areas may be protected from grazing to promote revegetation and reduce erosion.
- All disturbed sites will be contoured to naturally appearing topography and an appropriate soil profile.
- Soil profile compaction on disturbed areas must be controlled to assist root penetration and soil moisture intake.

7 CONTACTS

For more information about these guidelines or to discuss the possible presence of native grassland in specific areas, please contact:

Alberta Environment

Land Conservation and Reclamation Council

- Responsible for enforcement of conservation and reclamation standards for surface disturbances. Their scope covers both deeded lands and those public lands within the Special Areas.
- Act on a referral basis from the ERCB for well location on deeded lands with regard to environmental concerns.
- Administer the development and reclamation of regulated pipelines on all lands.

Hanna	854-5579	Red Deer	340-7742
Medicine Hat	529-3685	Wainwright	842-7535
Lethbridge	381-5490	Peace River	624-6333
Calgary	297-8295	Grande Prairie	538-5459

Department of Forestry, Lands and Wildlife

Public Lands Division

- Responsible for the administration of public land outside the Special Areas covered under the Public Lands Act. It is the acting landowner and is responsible for the issuance of surface dispositions including Mineral Surface Leases, pipeline agreements and Licences of Occupation. It identifies lands where seismic activity is not permitted through regulation, policy and referral. It also has officers who are responsible for conservation and reclamation standards of surface disturbances on public lands within municipal districts and counties and improvement districts.

Red Deer	340-5451	Calgary	297-6426
Lethbridge	381-5487	Wainwright	842-7548
Medicine Hat	529-3677	Peace River	624-6114

Fish and Wildlife Division

- Responsible for preservation and maintenance of fish and wildlife resources including habitat associated with prairie species.
- Act on a referral basis to evaluate impacts and make recommendations for mitigating action.

Red Deer	340-5142	St. Paul	645-6313
Lethbridge	381-5281	Peace River	624-6504

Special Areas Board

- Responsible for the administration of public lands within the Special Areas under the Public Lands Act. It is the acting landowner and is responsible for the issuance of surface dispositions.

Hanna	854-5618

Energy Resources Conservation Board

- Principal regulatory agency for the development of energy resources in the province. Its scope covers both deeded and public lands. It is responsible for well and pipeline licensing, production and completion, abandonment and general environmental issues.

Wainwright	842-7570	Calgary	256-1474
Medicine Hat	527-3385	Red Deer	340-5454

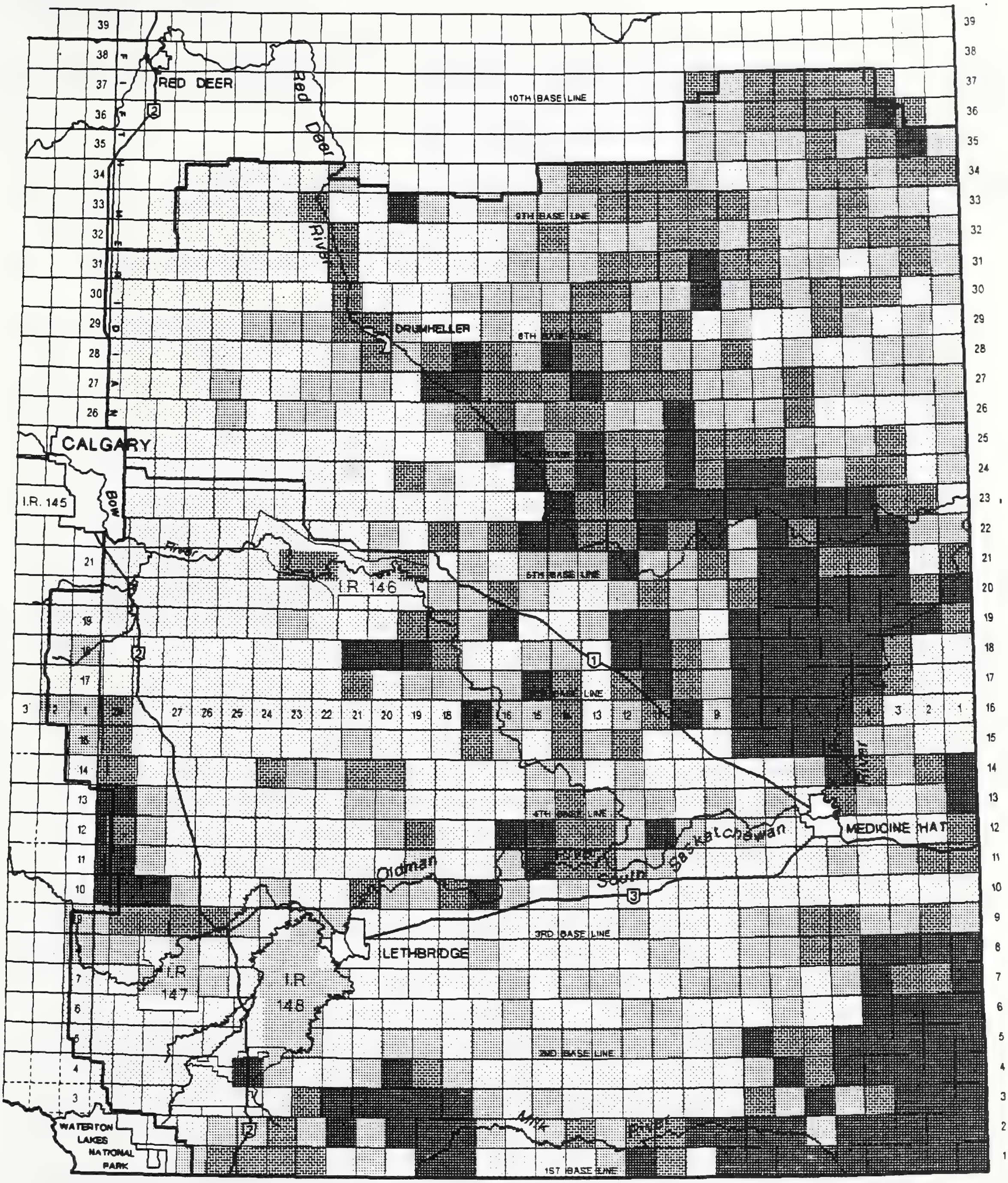
8 GLOSSARY

Ecosystem	An interacting complex of living and non-living forms within a given area.
Equivalent Capability	The ability of the land to support various land uses after reclamation similar to the ability that existed prior to any activity being conducted on the land (but that the ability to support individual land uses will not necessarily be identical after reclamation).
Fescue Ecoregion	An ecoregion developed mainly on shallow chernozemic soil. Rough fescue dominates the native vegetation.
Industrial	For the purposes of this document, industrial refers to petroleum exploration, development and transportation.
Minimal Disturbance	Reducing the area of disturbance from the survey perimeter (maximum) to that deemed necessary to safely conduct the activity as well as ensure the maintenance of equivalent soil capability.
Native Prairie	An area of unbroken grassland or parkland dominated by non-introduced species.
Rootzone	The part of the soil that is penetrated or can be penetrated by plant roots.
Three lift	A soil handling procedure where three layers (topsoil, upper subsoil, and lower subsoil) are selectively removed, stored and replaced.

Topsoil	The relatively organic-rich, darker coloured biologically active and fertile surface materials (and the equivalent in organic soils) suitable as a growing medium in uncultivated soils, or the plow layer in cultivated soils, whichever is thicker.
Topsoil/Rootzone Stripping (Overstripping)	Removing the uppermost portion of the soil ("A" horizon including the sod if present) and selective removal of the suitable soil immediately below the topsoil, in one operation.

Additional definitions can be obtained from Alberta Environment's Reclamation Glossary available from the Reclamation Research Technical Advisory Committee.

PETROLEUM ACTIVITY ON NATIVE PRAIRIE
CORE AREA MAP



☐ 0-25% Native Prairie

░ 26-50% Native Prairie

▒ 51-75% Native Prairie

▓ 76-100% Native Prairie

Cover estimates for this map are based primarily on information compiled from Environmentally Significant Areas inventories. These reports do not map all native prairie and have not been completed for all lands in the study area. Accordingly, the percentages depicted are good estimates only.

AL. 1.151

ERCB

Energy Resources Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-13

To: All Oil and Gas Operators

6 November 1992

WELL NAME REQUIREMENTS

Introduction

The Energy Resources Conservation Board (the Board) will be amending sections 2.050, 13.010, 13.020, and 17.010 of the Oil and Gas Conservation Regulations (the Regulations) with respect to the administration of well names. These amendments are in response to concerns raised by industry regarding well name administration and the need to simplify the application requirements and process. The Board has discussed and reviewed the changes with the Canadian Petroleum Association and the Independent Petroleum Association of Canada (Canadian Association of Petroleum Producers), the Small Explorers and Producers Association of Canada, and the Canadian Association of Petroleum Landmen.

Background

Historically, an individual well name was established as part of the well licensing process in accordance with the specifications outlined in section 13.020 of the Regulations. This well name then became part of the file in the Board's data systems and the requirement to keep the well name current was set out in section 13.010. The contents of the well name were based on section 13.020 of the Regulations. The well name has traditionally been used by industry and others to identify ownership of the well; however, this was not the intended usage. Additionally, a well's purpose was often gleaned out of a well name. Again, although it was not an intended use, the well name has also been utilized by industry to identify hard copy data submitted to the ERCB. The preferred or expected identification should have been in the form of the unique well identifier or the well licence number.

As it was not practical to eliminate well names, a simpler approach to the functionality and maintenance of this data element was required. Since the unique well identifier and well licence number are the most accurate means of identifying a well, the Board believes that the usage and maintenance of well names needs to be de-emphasized. This belief was confirmed through review and discussion with the above mentioned industry associations.

The changes to the Regulation will make well name changes optional and to be done primarily at the licensee's discretion. Additionally, the permitted/required contents of well names will be reduced.

REGULATION CHANGES

The initial creation of a well name and any changes by the licensee thereafter, will be administered as follows:

- The length of the well name shall not exceed 36 characters and spaces.
- A well name shall consist of four components placed in the following order:
  1. The licensee name by approved abbreviation.
  2. An open space for the applicant's use.
  3. The Board designated field containing the well location or approved abbreviation of the field, or where the well location is not contained in or adjacent to a designated field, the name of the strike area or approved abbreviation.
  4. The legal subdivision, section, township, and range in which the bottom hole of the well is located.
- The use of alpha designations in the location or prefixed to the location as presently set out in section 13.020 of the Regulations will be discontinued. No two well names will be allowed to be the same. The Board will no longer require the maintenance of a well name subsequent to its initial creation. Should the licensee wish to change a well name after its initial creation, the normal applicaiton requirements and fees will still apply.

Summary

Industry co-operation is required to ensure that all well correspondence and data filed with the Board clearly contains the unique well identifier and/or well licence number. Data containing only a well name may be returned for proper identification.

These changes are effective immediately and amendments to the Regulations will be forthcoming. All future well licence applications shall adhere to the new well naming conventions.

If there are any questions regarding these changes, please contact the Board's Well Licensing Section at 297-3700 or 297-8554.

J R Nichol

J. R. Nichol, P.Eng.
Manager
Drilling and Production Department

AL.1.151

ERCB

Energy Resources
Conservation Board

640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

IL 92-14

CANADIANA

NOV 30 1992

TO: All Oil and Gas Operators

18 November 1992

ISSUING OF ERCB BATTERY CODES

Section 7.001 and 7.002 of the Oil & Gas Conservation Regulations stipulate that construction and operation of a battery must have prior ERCB approval. Part of the approval process is the requirement to file an S-7 form (Appendix to Battery Application). No changes have been made to this process.

For reporting purposes however, operators sometimes require a battery code for a new battery prior to the issuing of the battery approval. In order to facilitate these operator requirements, the ERCB has decided to change the procedures for obtaining the battery code for a new battery.

Battery codes will be issued within a 24-hour time frame under the following conditions:

- operators must advise the ERCB, either by telephone or by fax,
- the information outlined on the attachment to this letter must be provided,
- once verified by ERCB staff, the battery code will be issued and a letter sent to the operator on the next business day,
- letters will be generated overnight for all requests made prior to 2:00 p.m. each business day, and will be mailed to operators on the next business day,
- requests made after 2:00 p.m. will be treated as requests for the next business day.

This change in procedures is being undertaken with the understanding that it merely facilitates the issuing of the battery code and does not relieve the operator of the obligation to file the appropriate information to obtain a battery approval in a timely manner.

Any questions or concerns with respect to this matter may be directed to Barb Ramsay at 297-4613.

R. T. Bording
Manager
Accounting Department

Attachment

ATTACHMENT TO IL 92-14

DATA REQUIRED FOR ISSUING A BATTERY CODE

Operator Code . . . . :

Operator Name . . . . :

Battery Name . . . . :

	LSD	SEC	TWP	RGE	M
Battery Location . . . . :	-	-	-		W

Field/Area Code of Battery . . . . :

*Battery Type . . . . :

Identify Sour or Sweet . . . . :

**Operator Contact Name . . . . :

**Operator Phone Number . . . . :

Fax data to 297-7303 or leave data on answering machine at 297-4206.

---

* Battery Type

CRUDE OIL		GAS		CRUDE BITUMEN	
1	TEST	7	TEST	12	GROUP
2	GROUP	8	GROUP	13	PRORATION
3	TEMPORARY	9	PRORATION - SE ALBERTA ONLY	14	SINGLE
4	PERMANENT SINGLE	10	PRORATION - EFFLUENT MEASUREMENT	15	TEMPORARY
5	PRORATION	11	SINGLE		
6	FIELDGATE / SATELLITE				

** For confirmation (if required) of data supplied.